ATTORNEY DOCKET NO. 57.0498 US NP
CUSTOMER NUMBER 37003

PATENT APPLICATION

METHOD AND APPARATUS FOR LIFTING LIQUIDS FROM GAS WELLS

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Priority Information:

UK Patent Application Number 0312652.1, filed 3 June 2003

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METHOD AND APPARATUS FOR LIFTING LIQUIDS FROM GAS WELLS

The present invention generally relates to an apparatus and a method for removing liquids from the bottom section of gas producing wells.

BACKGROUND OF THE INVENTION

Many gas wells produce liquids in addition to gas. These liquids include water, oil, and condensate. As described in the paper SPE 2198 of the Society of Petroleum Engineers of AIME, authored by R. G. Turner, A. E. Dukler, and M. G. Hubbard, "in many instances, gas phase hydrocarbons produced from underground reservoirs will have liquid-phase material associated with them, the presence of which can effect the flowing characteristics of the well. Liquids can come from condensation of hydrocarbon gas (condensate) or from interstitial water in the reservoir matrix. In either case, the higher density liquid phase, being essentially discontinuous, must be transported to the surface by the gas. In the event the gas phase does not provide sufficient transport energy to lift the liquids out of the well, the liquid will accumulate in the well bore. The accumulation of the liquid will impose an additional back pressure on the formation and can significantly affect the production capacity of the well". Over time, accumulated liquid can cause a complete blockage and provoke premature abandonment of the well. Removal of such liquid restores the flow of gas and improves utilization and productivity of a gas well.

There are many technical solutions that have been suggested in the prior art to solve the problem of accumulating liquids. Some of them are described briefly by E. J. Hutlas

and W. R. Granberry in the article entitled "A Practical Approach to Removing Gas Well Liquids" in the Journal of Petroleum Technology, August 1972, p. 916-922. Others are summarized in the United States patent 5,904,209. More recent advances in operating gas and other hydrocarbon wells are found for example in the United States patents 5,636,693; 5,937,946; 5,957,199 and 6,059,040.

Submersible pumps may also be used to overcome the above-described problem. However the costs of deploying such pumps are often not justified for low margin gas wells

On the other hand, it is known that production from low pressure reservoirs can be enhanced by jet pumps and artificial lift operations. For instance, hydraulic jet pumps have been used as a down hole pump for artificial gas lift applications. In these types of hydraulic pumps, the pumping action is achieved through energy transfer between two moving streams of fluid. The power fluid at high pressure (low velocity) is converted to a low pressure (high velocity) jet by a nozzle or throat section in the flow path of the power fluid. The pressure at the throat becomes lower as the power fluid flow rate is increased, which is known as the Venturi effect. When this pressure becomes lower than the pressure in the suction passageway, fluid is drawn in from the well bore. The suction fluid becomes entrained with the high velocity jet and the pumping action then begins. After mixing in the throat, the combined power fluid and suction fluid is pumped to the surface.

In the light of the above background it is an object of the present invention to provide effective and economically viable methods and apparatus for cleaning gas wells.

SUMMARY OF THE INVENTION

In accordance with a first aspect of the invention, there is provided an apparatus for reducing the level of liquids at the bottom of a gas producing well comprising a constriction or throat section in which a production gas flow from the well generates a low pressure zone having a pressure less than the ambient formation gas pressure and at least one conduit providing a flow path from an up-stream location within said well to said low pressure zone.

The invention proposes to exploit the flow of the produced gas to create a differential pressure between a location that is preferably located above the producing zone and a location that represents the maximum tolerable level of liquids in the well. The latter level is preferably set below the gas producing zone and hence most preferably immediately below the lowest perforation penetrating the gas bearing formation. The height or distance that separates these two locations and over which the apparatus lifts the liquid may span more than 5 meters, in some wells even more than 15 meters.

Preferably, the constriction is a Venturi-type constriction having an extended section of small diameter in between two sections where the flow pipe diameter tapers from its nominal diameter to the small diameter. However other constrictions such as orifice plates may be used.

The flow path between the up-stream location and the low pressure zone is provided by a conduit such as a tubular pipe. The conduit is preferably straight as even a limited number of bends in the tube induce a pressure drop that is lost for lifting the liquids. Its upper end preferably terminates at a location where the constriction has its minimal diameter. The conduit itself is best made of resilient material, such as steel, capable of withstanding the wear and tear in a subterranean environment.

In a preferred embodiment the conduit is flexible or capable of expanding and contracting, e.g. in a telescopic manner, in the longitudinal direction. When attaching a floater to its lower end, the conduit is adaptable to a changing level of liquid in the well.

In another preferred embodiment the conduit has at least one additional opening at a position between the two locations, hence, in a section of the well where gas is produced and can enter the tube through the additional openings thus provided. The gas reduces the weight of the liquid flowing through the conduit.

Whilst the openings could in principle be located along the length of the conduit it is preferred to position them at one location distributed around the circumference of the conduit. Most preferably the number of openings is restricted to exactly one, as it was found that additional openings do not result in a significantly increased performance of the apparatus.

When used in combination with an expanding or flexible conduit, it is preferred to have the additional openings arranged such that the distance to the lower end of the conduit remains constant. In this manner it is ensured that the additional openings are located at a constant height above the liquid level in the well, even when the influx of liquids into the sump of the well increases and, hence, the sump level rises.

In a preferred embodiment the ratio of the cross-sectional area of the additional opening and of the conduit is in the range of 0 to 1, though even larger openings in form of longitudinally extended slits could also be used.

According to a second aspect of the invention there is provided a method for maintaining or reducing a level of liquids at the bottom of a gas producing well comprising the steps of constricting the production gas flow at a location within the well to generate a low pressure zone having a pressure less than the ambient formation gas pressure and providing a conduit to establish a flow path from an up-stream location within said well to said low pressure zone.

In a preferred embodiment the method comprises the further step of determining a gas flow rate, a height over which liquids have to be lifted to reach the low pressure zone and a number representing the size of the constriction such that the low pressure in the low pressure zone is sufficiently low to lift liquids over said height. Where possible these steps are performed prior to the deployment of the constriction and conduit.

These and other aspects of the invention will be apparent from the following detailed description of non-limitative examples and drawings.

BRIEF DESCRIPTION OF THE DRAWINGS

FIG. 1A illustrates elements of an apparatus to pump liquids from the sump of a gas well in accordance with an example of the invention;

FIG. 1B shows a variant of the example of FIG. 1A;

FIGs. 2A-C illustrate further examples of an apparatus to pump liquids from the sump of a gas well in accordance with an example of the invention elements;

FIG. 3 illustrates important parameters for adapting an apparatus in accordance with the invention to a given well environment;

FIG. 4 is a graph useful for a process of adapting an apparatus in accordance with the invention to a given well environment;

FIG. 5 is a flowchart illustrating a process of adapting an apparatus in accordance with the invention to a given well environment; and

FIG. 6 is a plot comparing the performance of variants of the invention.

EXAMPLES

Referring first to the schematic drawing of FIG.1, there is shown a gas well **10** with casing **11** and gas production tubing **12**. Perforations **13** penetrate the casing to open a gas producing formation **101**. A sump **14** at the bottom of the well **10** is shown filled with water or hydrocarbon condensates.

The present invention proposes to latch onto the terminal end **121** of the production pipe a flow constriction **15**. A flow constriction of the type shown, often referred to as a Venturi, is known to generate a pressure differential between the constriction section and the surrounding sections of the flow pipe. The amount of the pressure differential depends mainly on the constriction dimensions, i.e. the diameter of the constriction **15** versus the nominal diameter of the production pipe **12**, and the flow rate of the medium passing through it. From the constriction section **15**, a small pipe or riser tube **16** provides a fluid communication to a location **161** closer to the bottom of the well. At the surface, there are further gas extraction facilities **17** to produce the gas and handle its transport further down stream.

In operation gas enters the well **10** through the perforations **13** and flows through the constriction section **15**, thereby creating a differential pressure DP= P0 - P1. The lower pressure P1 at the constriction lifts liquids from sump. The liquid exits the upper opening or nozzle **162** of the riser tube **16** as a mist or in an atomized form to be carried to the surface by the gas flow.

It is important to note that the pressure differential P provided by the constriction may not be sufficient to lift liquids from the sump under some flow rate regimes. To improve the device, a venting hole or opening **163** can be added to the riser tube at a location between the lower end **161** of the tube **16** and its upper nozzle **162**. This variant of the present invention is shown in FIG. 1B.

Through the venting hole **163**, gas from the production zone can enter the conduit and mix with the liquids. The resulting mixture has a lower density and can thus be lifted higher by the same differential pressure.

In FIG. 2A, there is show another example of an arrangement in accordance with the present invention making use of similar or identical elements to those in the examples described above and hence using similar or identical numerals to refer to those. In the present example, however, a riser tube **26** is arranged in an off-centered position relative to the constriction **25**. The riser tube is essentially straight without bends and less of an obstacle within the constriction. The nozzle **262** is located above the throat or narrowest section of the Venturi in a zone where the pressure differential may be slightly reduced when compared to the pressure differential within the throat section itself. However the advantages of having a straight riser tube may outweigh this loss. A venting opening **263** is provided near the bottom end **261** of the riser pipe **26**.

In the variant of FIG 2B, the riser tube **26** terminates in a funnel **262** that bends to open into the section of the constriction **25** that has the smallest diameter and, hence

the highest differential pressure. The opening **262** broadens so as to minimize the pressure drop due to the bend in the flow path of the liquid. A venting opening **263** is provided near the bottom end **261** of the riser pipe **26**.

A further variant as illustrated in FIG. 2C, the riser tube **26** carries at its end a floating element **264**. In connection with a flexible section **265** of the tube, the floater ensures that the opening **263** is maintained at a constant height above the liquid level **14** in the well **10**. The floater element **264** can be a gas tight housing. The flexible section **265** can be implemented as expansion bellows such as shown in FIG. 2C, or as a telescopic joint, or, in fact, as a compliant part of the tube **26** that bends or straightens slightly in dependence of the position of the floater.

Though the precise parameters determining the location and dimensions of the intermediate opening **163, 263** or openings are to be described in more detail below, it is the role of the hole to allow the passage of production gas into the liquid flow within the riser tube **16, 26**. The resulting gas/liquid mixture has a lower weight than the liquid and, even a low flow rate of the production gas can be used to lift liquids from the sump. Or, alternatively, the length (or height) of the riser tube **16, 26** and, thus, the height through which the liquid is lifted can be increased at an otherwise constant gas flow rate from the well.

In the following a detailed description of important design and other parameters is given that can be applied for the purpose of installing and operating devices in accordance

with the present invention. Reference is made to FIG. 3 that depicts parameters and coordinates as used in the following.

The Venturi pump **30** in which the main flow of gas creates a differential pressure which is used to lift liquid from the sump **S** at the bottom of the well to the Venturi throat **V**, where it will be atomized and then carried upwards with the main gas flow. Liquid droplets may subsequently touch the wellbore walls and form a thin liquid film which flows back downwards, so the process may require several stages.

If the pressure difference between location **S** and **V** given by P = PS - PV is sufficiently large, liquid can be lifted from **S** to **V**, a total height Ht = **H1** + **H2**. Liquid will not flow unless the pressure difference P can overcome the hydrostatic head, i.e. unless

[1] $$P > Dl\ g\ (\mathbf{H1} + \mathbf{H2})$$

where Dl is the density of the liquid and g the acceleration due to gravity. The pressure difference P generated by the Venturi is likely to be small, so that the height **H1** + **H2** will be small. Under these conditions the Venturi has to be placed sufficiently close to the pool of liquid to be lifted.

If relation [1] is not valid, gas (of density Dg < Dl) can be introduced into the vertical riser tube at the aperture **Ai**, so that the density of the gas-liquid mixture in the pipe **31** is reduced to Dm < Dl, with Dm sufficiently small that

[2] $P > Dl\ g\ \mathbf{H1} + Dm\ g\ \mathbf{H2}$

In a typical well several parameters are available for optimization amongst which there are the differential pressure P generated by the Venturi constriction, the height **H1** of the gas inlet and its cross-sectional area **Ai** and the cross-sectional area **At** of the riser tube.

The differential pressure DP in a Venturi due to the flow of the produced gas can be estimated using

[3] $DP = (1/2)\ Dg\ Ugv^2\ (1 - k^4)$

where Ugv is the gas velocity in the constriction and **kdw** is diameter of the Venturi constriction as a fraction k of the nominal diameter **dw** of the gas production tube. The hydrostatic pressure drop in the gas-filled well is added to this pressure DP to obtain

[4] $P = (1/2)\ Dg\ Ugv^2\ (1 - k^4) + Dg\ g\ (\mathbf{H1} + \mathbf{H2})$

The flow can be analyzed in terms of the liquid velocity Ul in the lower riser tube (of length **H1**), the ratio A=**Ai**/**At** of the gas inlet cross-sectional area **Ai** to that of the riser tube **At**, B=A sqrt(Dl/Dg) where "sqrt" denotes the square root operation, and G=**H2** g Dl / P. The latter parameter G can be interpreted as a non-dimensional number indicating the capability of the device to lift liquids from the sump **S** with G = 1 corresponding to the case where the differential pressure P would just be capable of lifting liquid a minimum distance **H2** required for the operation of the device.

Using the above parameters an approximation of P can be calculated as

$$P = (1/2)\ Ul^2\ Dl\ (1 + 2A^2 + 2B\ (1 + Dg/Dl)\ \mathrm{sqrt}\ (1 + G\ \mathbf{H1}\ /\ (Ul^2\ \mathbf{H2}))) + (1 + 2A^2)\ Dl\ g\ \mathbf{H1} + \mathbf{H2}\ g\ Dl\ /\ Fl \qquad [5]$$

where Fl is the liquid volume fraction

$$Fl = 1\ /\ (1 + B\ \mathrm{sqrt}(1 + G\ \mathbf{H1}\ /\ (\mathbf{H2}\ Ul^2)))$$

Equation [5] can be evaluated either numerically or approximatively. In FIG. 4 there is shown a plot of $Ul^2\ Dl\ /\ 2P$ as a function of **H1** / **H2** for different values of the parameter B (Curves **a**, **b**, **c**, **d**).

When using the novel devices it is important to know the differential pressure P that can be generated by the Venturi pump, given the expected gas flow rate Q in the well, together with the height **H2** through which the liquid is lifted. With the knowledge of P, an estimate can be determined of a likely value for G, preferably using a minimal likely value for P. Using then a value of B such that B > G-1. To optimize the liquid flow rate, it is preferred to make B as small as possible whilst maintaining the condition B > G-1 above. A plot similar to that in FIG. 4 can be used to derive an expected liquid velocity Ul, and then select the cross-sectional area At of the main riser tube so that the volumetric flow rate (Ul **At**) pumped upwards exceeds the rate at which water is thought to be entering the well.

The above steps are set out in the flow chart of FIG. 5 including the steps of:

1. Determining a reasonable value for A = **Ai/At** (STEP **50**). The area **Ai** of the hole through which gas enters the main riser tube (which lifts liquid to the Venturi throat at **V** in FIG. 3) is likely to be of the order of the cross-sectional area **At** of the riser tube itself. For example A = 0.5 is a possible choice.

2. Given the densities Dl of water and the downhole density Dg of gas, B = A sqrt(Dl/Dg) can be estimated (STEP **51**).

3. Assuming that the height **H2** is known by which water must be lifted for the device to be functional, i.e., without the opening **Ai** being blocked, the differential pressure P that has to be generated by the Venturi constriction can be determined (STEP **52**).

4. The non-dimensional quantity G = **H2** g Dl / P must be smaller than B + 1 for the device to operate, and a reasonably safety margin is given by for example the choice $G = 2(B + 1)^2 / (4B + 3)$. This gives a value for G and a design target for P. If G < 1 it would be possible to lift water to a height **H2** without the introduction of gas, however the present example is based on the assumption that G > 1.

5. For the design of the Venturi the value k for the ratio of the Venturi throat diameter to its inlet diameter is the most pertinent design parameter. Furthermore an estimate or knowledge of the downhole velocity Ug of the gas and the

downhole gas density Dg is required (STEP **53**). The differential pressure DP = (1/2) Dg Ugv^2 $(1 - k^4)$ allows the calculation of the constriction parameter k (STEP **54**).

The value of k must not be so small that the Venturi is likely to become blocked. In case the resulting value of k turns out to be too small (STEP **55**), a value of G closer to the maximum B + 1 could be chosen (STEP **56**), with the risk that such a design would be closer to the theoretical operating limit and would therefore be less robust.

6. If the gas flow rate in the well is high, the value of k obtained in step 5 will be very close to 1 (STEP **57**). Under such conditions the amount of gas required to lift the water in the main riser tube is reduced, thereby reducing uncertainty from the design by allowing for a smaller throat diameter (e.g. k = 0.5). This leads to an increase in the pressure differential P and the above design procedure can be reversed in order to select A (STEP **58**), which will be smaller than the value A = 0.5 chosen in STEP **50** as the starting point for the design. Thus in a well with sufficient gas flow there is a greater degree of freedom in choosing the parameters k and A.

7. The water or condensate level within the well is a distance **H1** below the point at which gas enters the main riser tube. For the device to operate we require H1/H2 < 1/G. The range of acceptable values for H1 is therefore not large, and a preferred choice for H1 is close to the value H2/(2G), or within the immediate vicinity of the bottom opening of the riser tube.

8. Equation [5] can be evaluated numerically or through approximations in order to predict the liquid velocity Ul in the bottom section of the riser tube. Typical results of equation [5] are illustrated in FIG. 4. The choice of Ul enables the selection of the diameter of the main riser tube (STEP **59**). This diameter is preferably small compared to the diameter of the well and small compared to the throat of the Venturi constriction, in order to ensure that the pressures in the Venturi are not adversely affected by too large an injection of gas/liquid mixture.

The following description represents a way of applying the above steps to a specific well.

The gas flow rate in the well is 0.22×10^{6} m^3/day at STP (1 bar, 15 C = 288 K). The downhole pressure and temperature are assumed to be 38 bar and 50 degrees C.

Assuming that the gas is ideal, the volumetric flow rate at downhole conditions is 0.079 m^3s^{-1}. The gas production tubing inner diameter ID is 4.4 inches. The tubing cross-sectional area is S = 9.8×10^{-3} m^2 so that the downhole velocity in the tubing is vd = 8.1 ms^{-1}. A gas gravity of 0.65 can be assumed, corresponding to gas density at standard conditions of 0.78 kgm^{-3}. The density Dg of the gas at downhole conditions is 25.3 kgm^{-3}.

The differential pressure generated by a Venturi with ratio of throat to inlet diameters k = 0.5 is 12.4 kPa (1.8 psi) using equation [3]. Evaluating the non-dimensional quantity G = **H2** g Dl / P, the pressure required to lift liquid a

height **H2** divided by the pressure differential generated by the Venturi. The density of water is $Dl = 1000\ kgm^{-3}$. If **H2** = 15 m then G = 11.9; whereas if **H2** = 40 m then G = 31.6.

With a smaller Venturi constriction of k = 0.35, the differential pressure generated is 54.5 kPa (7.9 psi). If **H2** = 15 m then G = 2.7; whereas if **H2** = 40 m then G = 7.2.

Choosing a value for B = A sqrt (Dl/Dg) wherein the ratio A = **Ai/At** of the gas inlet cross-sectional area **Ai** to that of the riser tube **At**, and Dg is the downhole gas density. If B < G - 1 the device will not operate, because insufficient gas enters the main riser.

The four values of G found above correspond to minimum values B = 10.9, 30.6, 1.7, 6.2 and hence to minimum values A = 1.7, 4.9, 0.27, 0.99. The first two values are considered not small enough to be valid (inlet area exceeding riser tube area) The last value is close to the practical limit, and corresponds to a gas inlet which has the same cross-sectional area as that of the main riser tube. The most viable design based on the above calculation corresponds to a Venturi with k = 0.35 and **H2** = 15 m, for which B = 3 (leaving an additional safety margin compared to the minimum value of 1.7) and A = 0.48.

Looking at the desired flow rate of 80 m^3 of water for every million m^3 of gas (at standard conditions), the rate at which water must be raised is 17.6 m^3/day = $2\times10^{-4}\ m^3\ s^{-1}$. FIG. 4 shows that the velocities are typically greater than $Ul = 1.0\ m\ s^{-1}$. The main riser tube therefore has to have an

area $2x10^{-4}$ m^2, which corresponds to a pipe of diameter 1.6 cm, which may be compared with the tubing inner diameter 11.17 cm.

The Venturi can be hung onto the tubing level with the top of the perforations with the riser tube bridging the perforated production zone of about 15 m depth, so that water is lifted by **H2** = 15 m. The design above indicates that the Venturi has preferably a throat/inlet diameter ratio k = 0.35, as k = 0.5 would not suffice, and that the lift height **H2** = 15 m can be attainable. The main riser which lifts water to the Venturi throat would have a diameter of 1.6 cm and a cross-sectional area **At** = 2 cm^2. The area **Ai** of the gas inlet through which gas enters the main riser would be **Ai** = 0.48**At**.

Further experimental data are shown in FIG.6, which illustrates the effects of differently sized venting holes (such as openings **163**, **263** in FIGs. 1 and 2). In the graph, the ordinate values indicate the flow rate of liquid extracted from a sump measured in cubic meters per hour. The abscissa indicates the differential pressure in Pascal. The experiment without venting hole - corresponding to a device as shown in FIG. 1A - is denoted by diamond shaped markers. The values derived from an experiment with a 1mm diameter hole are plotted as squares. And the values derived from an experiment using a 3mm hole are plotted as triangles.

The experiments demonstrate the beneficial effects of an additional opening at low DP. In addition it is shown that there is a drop in performance when using a larger opening area Ai.

While the invention has been described in conjunction with the exemplary embodiments described above, many equivalent modifications and variations will be apparent to those skilled in the art when given this disclosure. Accordingly, the exemplary embodiments of the invention set forth above are considered to be illustrative and not limiting. Various changes to the described embodiments may be made without departing from the spirit and scope of the invention.